STATE OF CALIFORNIA
CONSUMER POWER AND CONSERVATION FINANCING AUTHORITY

Rulemaking:
Establishment of Target Reserve Level for the California Power Authority Investment Plan

Docket 2002-07-01

FINAL DECISION
D03-001

January 17, 2003

California Consumer Power and
Conservation Financing Authority
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INTRODUCTION

In this final decision of the reserves rulemaking, the California Consumer Power and Conservation Financing Authority (Power Authority) believes our fundamental goal has been accomplished. The Power Authority has conducted a collaborative proceeding with other agencies in the state (California Energy Commission, California Public Utilities Commission, California Independent System Operator) and solicited and received significant input from other entities and from the public.

We have created a rule that serves the purpose of our investment plan and accommodates the views of the CPUC, CEC, and ISO who agree with the fundamental assumptions for determining reserve requirements set forth herein. Of equal importance, in this final rule, the CPA also accepts several changes proposed by participants to the proceeding and we clarify other questions posed in comments to the previous decision drafts.

- First, we recognize and clarify that, while the Power Authority strongly believes that reserve targets should be set, the actual reserve level applicable to each individual utility will vary by portfolio, technology and the application of numerous other factors.

- Second, since procurement decisions and orders are accomplished for each utility in proceedings involving that utility and its regulator, e.g. The CPUC for the IOUs, various boards and governing bodies for Municipals, etc., it is in those proceedings that actual decisions are made with respect to resource procurement, taking into account the numerous factors that bear on such decisions, i.e., cost/benefit trade-offs, specific evaluation of resources, level of acceptable risk, etc.

- Third, while we establish a reserve target and range in this rule, this determination reflects our current circumstance. It is essential for the Power Authority to review the target annually to ensure that in light of our rapidly changing electricity environment the targets and supporting assumptions continue to make sense.

- Fourth, while we recognize that this target is not binding on any regulatory body, we consider it important for at least two significant purposes. First, it serves its primary purpose as a target reserve level for purposes of developing the CPA's second annual Electric Resource Investment Plan that is due in February 2003. Second, we will supply this recommendation to various regulatory proceedings where reserve decisions are currently being considered, where each regulator will review, with its utilities, actual reserve levels. We expect that these, and other decision-making bodies will take notice of this rulemaking in their deliberations.

- Fifth, while we maintain our policy recommendation that 25-50% of this reserve level consist of demand-responsive programs, we recognize that demand-responsive load will be phased in at different paces for each utility. In that light, it will be essential to annually evaluate both the target level, its cost-effectiveness, and the mix of demand-response programs .[1] These reviews should decide what demand programs continue to be beneficial, and what adjustments need to be made based on program costs, avoided power costs, resource portfolio diversity, and other economic, environmental and social criteria.

- Sixth, in considering the comments received by the Power Authority since the issuance of the draft decision, it remains clear that the input assumptions and the development process of the target Reserve Level is actually more important than the number itself. Variations to the recommended reserve level will be appropriate for any given utility based on the nature of the resources, the fuel source, the age and historic performance of the equipment, market conditions, contract terms and conditions, desired reliability levels, risk tolerance, level of capacity actually under contract vs. capacity acquired in spot transactions and numerous other factors.

FINAL RULE

The California Consumer Power and Conservation Financing Authority finds the following with respect to the level of electric supply capacity as measured against system peak demand ("Reserve Level") needed for reliable and affordable electric service.

Each utility should demonstrate to its appropriate regulatory body, and to others as required, that the utility owns, controls or reliably can acquire capacity that is expected to

[1] The CPUC is at this time in the midst of a proceeding addressing demand programs and will make findings in that proceeding about appropriate application and targets for the IOUs.

be available to the utility to reliably serve its load. (“Dependable Capacity”) Each utility should be able to demonstrate using appropriate criteria how it will achieve Dependable Capacity in an amount equal to no less than 17% in excess of its peak needs (i.e. 117%), as measured against its projected monthly peak.

This recommended capacity requirement should be used as a starting point by each regulatory authority in setting procurement guidelines for its utilities, the target may be adjusted up or down pursuant to analysis and relative weighting of the factors listed below and other factors deemed important by the regulator. The likely outcome of such analysis is that, when the reserves of all the utilities are taken together, actual reserves for California’s electricity system will fall within the 15 – 18% range.

Sources of capacity are expected to include traditional and renewable resources owned by the utility, capacity and energy supply procured from resources owned by others and rate design structures and demand programs that function as available capacity. We recommend that contracts providing these resources should be of varying length and terms. This approach helps prevent oversupply, allows LSEs flexibility to adjust their energy procurement in response to changes in demand, and provides an opportunity for demand resources to develop. The Power Authority will implement its investment strategy to facilitate renewable, demand-based and traditional resources, to assist the utilities in meeting these targets in the most cost-effective way.[2]

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[2] The Power Authority’s investment strategy is set forth in its report “Clean Growth: Clean Energy for California’s Economic Future,” submitted to the Governor and Legislature in February 2002, as updated and /or amended from time to time (“Investment Plan”).

The Power Authority further recommends that demand programs be created and targeted to comprise between 25 and 50% of this Reserve Level. This would equate to demand-based reserves of approximately 5 -10% of the dependable capacity that provides system peak load and needed reserves. At the same time, the Power Authority recognizes that demand programs take time to develop. These targets will likely be phased in over time and should be reviewed regularly and adjusted as needed with consideration of costs, supply alternatives and unique benefits provided by demand response.

The recommended reserve level should be reviewed annually and updated as needed by the CPA in connection with the preparation of its Electric Resource Investment Plan. A sufficient level of reserves depends on many complex and changing factors. Updates should consider future procurement decisions from the CPUC, the future Integrated Energy Policy Report from the CEC, the state of FERC standard market design, the status and timing of CAISO market changes, financial conditions of merchant generating companies and investor-owned utilities, and other factors.

STATEMENTS OF FACT

In setting these targets, the Power Authority recognizes the following facts:

1. Ultimate responsibility for setting procurement levels and plans rests with the regulatory authority which governs each utility, i.e. the California Public Utilities Commission (CPUC) for the investor-owned utilities (IOUs) and governing boards and city councils for municipal utilities (Munis) and special districts.

2. The recommendations in this decision are not binding on any regulatory body.
3. While recommending 17% Dependable Capacity as a Reserve Level, the Power Authority recognizes that actual reserves for any particular utility will likely vary depending on the composition of the portfolio of each utility.
4. Many factors affect the actual reserve level needed by any particular utility. These factors include at least the following, and may include other items deemed critical by a particular regulator:
    a. The operating condition of power plants (i.e. age, maintenance history, etc.
    b. Technology of resources
    c. Terms and conditions of supply or load contracts
    d. Current rules and quantities of direct access
    e. Level of risk tolerance and reliability desired by ratepayers
    f. Type of price responsive retail tariffs in effect
    g. The level of excess and/or uncontracted capacity in California and neighboring states
    h. The benefits of non-coincident peak loads
    i. The status and competitiveness of ISO and regional energy markets
    j. The financial condition of merchant generators, investor-owned utilities, and other market participants
5. Demand response tariffs and programs take time to develop. Targets for such programs should be reviewed by applicable regulatory bodies as they develop. Demand programs should be developed with an eye on their cost-effectiveness

and in comparison with alternatives while taking into account the intangible costs and benefits of such programs.

6. As new pricing tariffs emerge from PUC proceedings such as the Dynamic Pricing rulemaking (R02-06-001), upcoming General Rate Cases and other future proceedings, reserve targets should factor in the effectiveness of these programs.
7. Current and future estimates of resources that may be available in California and the western region should take into account the financial conditions of market participants

The Power Authority expects that the reasoning and information stemming from this rulemaking will offer helpful guidance to the appropriate regulatory bodies when considering procurement policies and deciding whether or how much to differ from these recommendations based on their particular circumstances. The Power Authority also notes that this rulemaking was cited in the recent Procurement Decision in CPUC Proceeding R01-10-024; and provides this Final Decision as further input to that ongoing proceeding.

STATEMENT OF SUPPORTING PRINCIPLES AND CONCLUSIONS

1. Load serving entities are responsible, under the guidance of their appropriate regulatory authority, to procure power and reserve capacity sufficient to meet their needs, satisfy reliability criteria, minimize costs, and reflect a level of risk tolerance acceptable to their customers and regulators.

2. The primary purpose of reserves is to ensure system reliability. In the developing competitive marketplace, increased reserves also help maintain competitiveness and rational energy prices. It is unclear, however, if the cost of acquiring these additional reserves offsets any savings in energy prices provided by competition.
3. Provision of electric service has changed substantially in the last several years with the divestiture of generating units and the introduction of wholesale market structures. These changes require a new approach to calculating reserves because diverse ownership of generating resources has introduced new incentives for strategic market behavior and profit maximization and may affect incentives to adequately maintain generating resources.
4. Introduction of new economic dimensions into reserve calculations also means that we may need more reserves now than in the past. In the time of vertically integrated utilities with a regulated duty to serve availability and behavior was predictable. Under the new paradigm withholding can increase profits. Contracts can create a need for suppliers to hold back capacity to hedge financial risk. Both these factors and others drive up the reserves needed for stability and reliability. Dependable Capacity must be just that – dependable. Simply counting installed capacity without taking into account ownership, contract rights, or other measures determining availability is inadequate. Resources "counted" for reserves must be supported by real commitments. For example, supply should either be linked to specific equipment, supported by contract terms and conditions (as in the case of DWR contracts,) backed by firm import commitments, demonstrated historic

performance (such as with QF contracts) or other means of demonstrating a high probability of actual availability.

5. All generation owners or operators should be required to report to the CAISO their contractual commitments for the output of their equipment on a regular and timely basis. Without such reporting it will be impossible to determine the level of reserves available for load in California and consequently difficult for the Power Authority and other regulators to accurately determine the need for additional investment.
6. Currently, FERC has imposed a "must-offer" requirement on generators in California and the other western states. However, the eventual disposition of such a requirement is far from certain, and in its current form, it is a weak provision. Since the existing must-offer requirement may be short lived, capacity located in California, but not contractually committed to an LSE, cannot be fully relied on as available capacity for California load. Our recent experience with blackouts and price spikes supports this conclusion. We therefore conclude that at present, any capacity in California not contractually committed to serve load in California, should be counted at no more than 50% when calculating existing aggregate reserve margins. This derate reflects our experience of the last several years, but is by no means the last word on the subject. It assumes that the owners of uncontracted capacity will participate in some measure in spot markets but that they cannot be completely relied on for California. As time passes, this assumption needs to be reviewed and adjusted to be consistent with experience. If

this assumption proves to be too optimistic, the number should be adjusted downward.

7. If sufficient capacity to meet target reserve levels is not built and/or is unable or unwilling to contract with LSEs in California, the Power Authority will fulfill its statutory responsibility, and will be required to invest in supply or demand based capacity to be made available at cost of service rates to fill any needed shortfall.
8. Any reserve capacity requirement calculation must take into account:
    a. A de-rate for the difference between installed and dependable capacity (this is factored in *before* calculating reserves)
    b. Forced outages (typically in the range of 5-10%)
    c. Operating Reserve (approximately 7%)
    d. Regulating Reserve (1-2%)
    e. Load Forecast Error (1-2%)
9. Totaling all of these components would argue for dependable reserves between 14% and 21% *without* taking into account any adjustments to account for market behavior. However, the likelihood of coincident maximums in all categories is small and argues for some judgment in setting a target. Understanding that each LSE and its regulator will set reserve targets individually, but recognizing at the same time the value of a general target, the Power Authority recommends 17% dependable capacity above monthly system peak demand as an appropriate starting target.
10. The level of reserves required clearly depends upon the reliability and availability of the underlying resources. LSE's that directly control substantially all of their

energy needs (including outages, financial contingencies, reliability reserves, etc.) will likely need reserve levels that are lower than an LSE that extensively participates in spot market transactions and relies on uncommitted capacity.

11. The Power Authority recommends that demand-reserves programs should account for 25 –50% of reserve capacity target. Given a recommended level of 17% for overall dependable reserves, 25-50% of reserves served by demand programs would amount to approximately 5-10% of peak load. In a system the size of California, with an expected normal peak of about 50,000 mw, this would indicate demand reserves of 2,500 to 5,000 mw.
12. The Power Authority finds that each LSE should own or contract for 17% dependable capacity above its monthly peak need to account for reliability reserves (operating, regulating, load forecast error,) normal equipment derates and forced outages. Acquiring reserves at this level of capacity should be sufficient to ensure that both purchases from the spot market, and spot market prices themselves, are kept within reasonable bounds and will not affect the reliable operation of the transmission system.

PROCEDURAL BACKGROUND

The Power Authority issued the notice of Rulemaking in this proceeding on July 24, 2002. At that same time a procedural schedule was published providing public review and comment periods on this matter. Comments were received from the following parties: Alliance for Retail Energy Markets, Alstom, Advanced Thermal Systems, California Energy Commission, California Independent System Operator, Consumers

Union, Independent Energy Producers Association, Pacific Gas and Electric Company and San Diego Gas and Electric Company.

In addition, at the September 6, 2002 meeting of the Board of Directors of the Power Authority, brief verbal comments were provided by the California Public Utilities Commission, and by interested members of the public. In addition to these comments, the Power Authority has reviewed numerous documents and reports from reliability standard organizations, regulatory bodies and economists in analyzing this matter and preparing conclusions for this rulemaking. The first draft decision was released by the Board of the Power Authority on September 20th. At that time a second public comment period was initiated which closed October 11th, 2002. During that period, the Power Authority received additional comments from the California Energy Commission, the California Public Utilities Commission, the California ISO, the Independent Energy Producers Association, Sempra Energy Resources and Consumers Union. These additional comments have been summarized in the comments section below.

A second draft of the rulemaking was released on October 15th, and further discussion occurred at the Power Authority board meeting on October 18th, 2002. In addition, an additional opportunity for public comment was given at the board meeting. This final rule has been prepared following the direction of the board of October 18th, 2002 and ;considering all the comments feceived since that time.

The Power Authority is aware of the continuation of numerous other proceedings in both state and federal jurisdictions that are occurring in parallel with this effort and continues to follow the relevant proceedings. For example:

- The California Public Utilities Commission is in the midst of establishing procurement rules for the utilities under its jurisdiction and issued significant procurement guidance for the IOUs on October 24th, 2002, with further filings and rulings expected into this year.
- The California ISO has filed numerous market design changes. One proposal includes a proposed capacity requirement. The state opposes this requirement since resource procurement is a state function. FERC has approved some of the changes proposed by the ISO while others, including the need for capacity obligations, have not been addressed. In light of the PUC procurement proceeding, this proceeding and other state actions, the ISO board has directed the ISO to request FERC to defer action on any capacity elements of market design until the completion of state efforts in this area or until November 1st, 2003, whichever occurs first.
- FERC itself has released its Standard Market Design Notice of Proposed Rulemaking ("SMD NOPR") proposing several market design features including a capacity adequacy requirement.
- The California Energy Commission opened a proceeding (02-IEP-01) on October 22nd, 2002 that will result in the production of an Integrated Energy Policy Report to the Governor by November 1, 2003.

Each of these proceedings approaches the concept of capacity adequacy requirement from a different perspective. This proceeding is necessary for the Power Authority to carry out its statutory duty to help assure the State has “adequate reserves.” We hope that the output of this proceeding will be a base element of guidance in other regulatory proceedings and in decision making processes about capacity at all levels, including state and municipal boards and city councils.

SUMMARY OF COMMENTS

A number of common themes occurred in the comments received in this proceeding. Nearly all commenters urged the Power Authority to recognize other proceedings and efforts underway at this time. Several commenters also urged the Power Authority to balance its efforts to increase infrastructure with effects that such investments might have on private companies desire to invest. A third common theme was the level of complexity involved in setting reserve targets and the number of variables and assumptions involved.

Advanced Thermal Systems noted that a regulated market contained a framework for advance planning and construction of capacity facilities prior to actual need. A deregulated market depends on price signals. Waiting for price signals creates lag time between need identification and construction of facilities. This delay can be expensive and may create the need for reserves above historic levels. It asserts that spot price signals are currently too low to incent investment in purely merchant facilities and that plants underway now should be shelved. Advanced Thermal believes that short-term behavioral conservation quantities will deteriorate rapidly and will only re-emerge if prices rise significantly. Long-term conservation effects will be product and service related and consumers will make choices based on economics as they develop. They also assert that demand will continue to grow based on increasing use of electrified products and that usage patterns will alter as technology develops. They express concern that Power Authority investment will compete with private investment and could skew the economics of private investment decisions.

Alliance For Retail Energy Markets recommends that the Power Authority adopt a reserve margin target of 12%. It asserts that a minimum reserve target should maintain reliability at peak demand and protect consumers against market volatility. The Alliance asserts that if reserves fall below that minimum target the Power Authority should create or finance investment, and that if reserves are above the threshold, public action is unneeded, and may conflict with incentives for private firms to provide capacity. It asserts that the availability of funding from the capital markets will regulate reserve levels effectively. It notes that Texas recently lowered minimum reserve requirements to 12% from 15.5%. Texas had projected reserves of 30.9% at the time the recommendation was adopted. The Alliance believes that market forces will develop reserves in excess of minimum levels. It asserts that reliability is no worse under market mechanisms and that under truly open competition, resources will develop in an economically rational manner. The Alliance asserts that continued behavioral conservation results require continual focus on maintaining customer awareness. It also assumes that aggressive investment by the Power Authority will increase rates. The Alliance concludes that reserves targets should not exceed 15%

Alstom described its capabilities as a vendor in providing information and technology with respect to the new electricity landscape. It notes that reserves can be provided in the form of megawatts or negawatts. Alstom believes that use of historic targets may be problematic, and that relying on reserve margins may be inadequate to ensure reliability. They also noted that in California reserves have commanded premium prices during times of scarcity and that this is consistent with other restructured environments around the country. Alstom believes that customer preferences should be factored into reserve and reliability decisions. They also describe different aspects of FERC's SMD NOPR and the requirements placed on LSEs, and the CPUC's open docket on demand response metering and pricing.

The California ISO (CAISO) noted that current electricity market structures are more complicated than those of the past and that the added complexity adds risk to both market prices and reliability. It notes that decisions left only to the market i.e. whether or when to build, fuel mix, etc., can affect reliability. It asserts that reliability assessments must account for fuel diversity, location, deliverability, transmission constraints, withholding incentives and the actual availability of resources to meet load. The CAISO maintains that a viable and stable platform to support investment is a critical need and that absent such a framework investment will be difficult and potentially inadequate. The CAISO recognized also the key role the PUC will play in the investment decisions of the IOUs.

It noted the importance and effectiveness of demand participation in any reserve regime and the importance of appropriate price signals in that regard.

The CAISO described the objective of its own market design filing and FERC SMD as an effort to bolster reliability and move procurement decisions away from real time and into the forward market in order to reduce ISO real time activity. The ISO noted that any reserve target must accommodate regional reliability council requirements as well as exhibit consistency with other proceedings currently underway. Finally the ISO recommended a monthly reserve responsibility of between 10% and 12% to support daily operational reliability and compliance with regional reliability mandates. At the same time, the ISO note that consistency in definition is critical in understanding any numerical reserve target. In sample calculations the ISO demonstrated that a 12% capacity margin could represent "installed capacity" reserve margins as high as 24% or "dependable capacity" reserves as high as 19%, depending on forced outage levels.

The ISO, in its additional comments, urged the Power Authority to use Dependable Capacity as the basis for calculation instead of Installed Capacity, citing the significant problems is using an Installed Capacity approach. We agree and have revised our approach. In addition, the ISO recommended an ongoing process to evaluate the target. We agree, and it is the intention of the Power Authority to visit the reserve target annually as it prepares its investment plan to both analyze the previous years trends and outcomes, and to look at projected trends, economic conditions and implications for the future. This will assure that we do not over-invest, or under-invest in providing needed resources.

The CAISO also asserts that it is not clear that additional reserves are needed under a competitive market than under a regulated market. We disagree. It has been clear from our recent disastrous experience that the reserves needed to support competition are greater than the reserves needed under regulation. The numerous investigations, documented withholding, exercise of market power, and rotating outages are stark evidence of this fact. While it may be possible to postulate a market model that supports the ISO position, we do not yet have such a model, and cannot proceed as if it were in existence at this time.

Pacific Gas and Electric Company (PG&E) acknowledged the significant changes that have occurred in the provision of electric service and the critical need to assign responsibilities and integrate regional and state efforts. PG&E also noted the number and scope of other proceedings dealing with reserve and supply adequacy and also recognized the regional nature of California's electricity supply. They also note that the benefits of any reserve margin need to be compared with the costs. PG&E also asserts that regardless of the engineering methodology chosen to determine reserve levels, (i.e. loss of load probability, value of service, expected contingency, etc.) some judgment still needs to be applied to the results. PG&E also posed several questions with respect to methodology that they assert need to be considered in determining reserve levels for a particular LSE. PG&E also provided a number of critical assumptions such as hydro conditions, contract terms, firmness of imports, deliverability, and others that can dramatically affect the reserve value of existing resources. PG&E was among a number of commentors who noted that the changes in the current landscape of electric service provision are substantial. They assert that simple reliance on historic methods, targets and processes is inadequate in our current environment due to these changes and that new thinking is required.

San Diego Gas & Electric Company stressed the need for coordination and asserted that the Power Authority should wait for the outcomes of related proceedings before taking action. San Diego also urged the Power Authority to participate in those proceedings. It noted that the questions posed in the Notice of Rulemaking are in and of themselves insufficient to establish reserve targets. San Diego noted that reliability council targets also must influence reserve levels and that definitions used for reserve calculations should be consistent with existing definitions.

In additional comments, San Diego continues to urge inter-agency and inter-jurisdictional coordination. We agree and are involved in all relevant proceedings as noted above. The Power Authority still finds that it must act to further needed reserves by completing this rulemaking with all relevant specific targets and recommendations rather than wait for the outcome of other proceedings.

Consumer's Union noted a number of considerations that substantially change the way reserves are calculated and accounted. They note that these changes may increase the level of reserves required to maintain reliability and assure stable markets. CU also postulated the possibility of different reserve levels for different classes of customers with cost responsibility assignment following the different levels. CU also encouraged coordination with the other proceedings and critical actors currently involved in reserve level calculation and determination. CU specifically noted the FERC SDM NOPR rules and target levels and the MD02 proposals of the California ISO. It noted the regional nature of California's electric supply and the need to understand events and processes in the region as well as in the state.

CU referred to the FERC July 17, 2002 Western Market and Infrastructure Assessment as underscoring both the regional nature of supply and critical concerns of potential deficiency in our current reserve picture. CU provided a list of possible reasons why current reserve levels should be higher than historic reserve levels including retirements, control of market power, the new incentive structure and tightening air quality standards. Finally, CU provided comments on the nexus between market design and reserve targets, FERC recommendations that at least 70% of energy should be secured through long-term contracts, the locational aspect of reserves, fuel diversity, and the possible role of customer choice in reserves targets with possible variations as to who pays for different reserve levels. CU also notes a role for reserves in both reliability and preventing market power.

Consumers Union in further comments supports the Power Authority's findings and conclusions and endorses the reserve targets proposed in the draft rulemaking.

The Independent Energy Producer's Association (IEP) urged consistent definitions of reserves and the need for establishment of clear roles for federal and state entities. The IEP urged that load serving entities be responsible for acquiring reserves and that targets for such acquisitions be clear. IEP urged that responsibilities to acquire reserves for load not overlap among entities. IEP also reminded the Power Authority that its role is to supplement, not supplant private investment. IEP commented that reserve targets are important to incent long-term investment and are related to risk tolerance. IEP asserted that load serving entities should be accountable for their own procurement strategies. IEP also stressed that certainty and stability of the political and investment landscape is critical for a stable framework in which to acquire reserves.

In its further comments the IEP supports clear assignment of responsibilities and clear establishment of targets. The Power Authority agrees on both counts and is committed to further that process. IEP also comments that the level of production provided by existing merchant resources and Qualifying Facilities has been consistently high.

California Energy Commission (CEC) commented on the numerous variables to consider in calculating a reserve percentage and the complex and detailed number of assumptions required in such a calculation. In addition to technical considerations, the CEC asserted that market imperfections also affect this calculation. It also expressed concern about the interplay between public and private investment incentives and the need for careful coordination of such efforts. The CEC noted the myriad proceedings underway and the critical need to coordinate the outcome of these proceedings. The CEC commented on the number of power plant applications in both California and the West over the last 2 years and the number of cancellations and deferrals of these projects. The CEC also asserted that between investments in energy efficient equipment and some persistence in conservation behavior that 50% of the conservation observed in 2001 was a likely quantity of permanent load and energy reduction.

The CEC believes customers should have the opportunity to respond to prices and would do so with sufficient information and price signals. The CEC notes also that demand response can play an important role in providing capacity and be just as effective as traditional capacity, particularly at peak load times. The CEC stressed the need for continued emphasis on demand side in the market. We agree and have made an increase of demand participation a mainstay of our investment strategy. The CEC believes that market design changes currently underway will increase the pressure on demand to participate by responding to price signals. Finally, the CEC recommended that the Power Authority not change its initial 15% target until other relevant proceedings noted earlier have been concluded.

In its further comments the CEC also urges the Power Authority to use a base of Dependable Capacity for its Calculations and recommendations. As noted above, we agree. The CEC notes that if Direct Access Customers all procure firm contracts, and, if the IOUs enter into sufficient contracts with uncontracted capacity in California, we will be closer to meeting our needed reserve levels. We agree, and we are hopeful that the interim procurement rules from the CPUC will cause sufficient contracting between the IOUs and merchant power facilities to provide for the level of reserves the Power Authority suggests are needed for each IOU.

The Power Authority does not control this contracting process, however, and accordingly, we continue to believe that uncontracted capacity in California must be discounted to 50% until it is signed up in a contract to serve California load. In addition, the Power Authority does not accept the proposition that all Direct Access load is fully sourced with firm capacity. In observing the market performance this last summer, it appears that the opposite may be the case.

DISCUSSION

A. Reconciling Numbers. The starting point for understanding all capacity calculations is clear definitions. *Installed capacity* is the technical rating of a piece of equipment. It is the output capability under normal conditions with everything at design specifications. *Dependable capacity* is the actual historic capability of the same unit. It is nearly always less than the installed capacity for many reasons. Some examples of such derates will help understand the reason for this fact. Run-of-river hydro facilities when stream flows are below maximum, thermal units whose output is limited when ambient air temperature is above design parameters, (a condition almost always associated with summer peak,) environmental constraints on water outfall temperatures (also almost always associated with summer peak conditions,) transmission constraints that prevent capacity that is available from being delivered, etc. This list is a small example of dozens of reasons that an aggregation of units, even when in service, has an available or *dependable capacity* substantially less than the installed capacity numbers.

It is helpful to understand that the various reserve target numbers that have been used in different ongoing proceedings are not as different as they seem. For example, the ISO recommends a 10-12% reserve margin. A careful reading of the ISO's proposal, however, indicates that this 10-12% reserves, is based on *unforced capacity* as the starting point. Unforced capacity is defined by the ISO as the *dependable capacity* of the unit further reduced by its historic forced outage rate. Forced outage rates are calculated as the percentage of time the unit is out of service due to some equipment failure or malfunction. It does not include maintenance outages. Forced outage rates are affected by resource age, technology, maintenance history, capital investment history, operating history and other factors.

An average 30-year old steam unit may have a forced outage rate of at least 10%, meaning at least 10% of the time it is out of service for reasons other than planned maintenance. This adjusts the installed capacity of a 500 MW unit to only 450 MWs of *unforced capacity* from which to calculate the 10-12% reserves the ISO suggests may be necessary. To compare that back to reserves calculated on a dependable capacity basis, the percentage numbers must be combined. This means that "unforced capacity" would be "installed capacity" minus a derate to get to "dependable capacity" minus a further derate for forced outages to get to "unforced capacity."

Historic forced outage rate averages for the fleet of equipment in California have been between 5-10%. Recent history shows a much higher outage rate - a concerning trend that must be monitored. Assuming a 10% outage rate, the ISO's proposed 10-12% capacity requirement of *unforced capacity* would translate into 20-22% reserves on a *dependable capacity* basis. This is because the 10% forced outage rate would need to be added to the desired level of 10-12% to represent a true comparison between reserves measured as unforced capacity and reserves measured as dependable capacity. If an additional adder for the difference between dependable capacity and installed capacity is added, the number gets even higher. If the average forced outage rate is higher, then the dependable capacity number must also be higher.

Many capacity calculations use a base of *dependable capacity.* The Power Authority proposed to calculate reserves based on this approach. As described above, dependable capacity represents an average derate for each resource based on the capacity actually historically available from that resource compared to nameplate capability. This excludes planned and forced outages. While this average derate varies with technology type, weather, age of equipment, hydrological conditions and other variables, it cannot be ignored. If a calculation is based on installed capacity, instead of dependable capacity, the installed capacity number must be considerably higher to account for an assumed derate. In light of the comments received from parties to the proceeding, the Power Authority has moved to a calculation based on dependable capacity. That means that each capacity resource, based on historic performance, demonstrated performance or other tangible measure will have a dependable capacity capability that differs, sometimes quite substantially, from its nameplate, or installed capacity rating. By using a dependable capacity base, the adder of 5% used in the initial draft as an assumed derate is removed from the 22% target, but *is factored in*, more accurately, by using the dependable capacity of each resource.

FERC in its SMD proposes a minimum 12% reserve capacity. It is not clear from the document if this 12% is based on installed or dependable capacity. Given how they describe its use, it appears to be based on dependable capacity. If the average dependable capacity of a group of units is 5% less than installed capacity, which is not an atypical de-rate factor, then the 12% proposed by FERC would become an 17% installed capacity reserve target. In addition, FERC stresses that its proposal is a minimum requirement and notes that regulatory agencies responsible for procurement will likely set much higher reserve level requirements.[3]

Historically, 15-22% reserves calculated on installed capacity, has been the range of capacity reserves. One technical support for this level of target comes from loss of load probability calculations. An assumption of loss of load once in ten years, which has been a typical starting point, produces installed capacity reserve requirements in approximately the 18 – 20% range.

[3] However, as the Power Authority and CPUC have noted, FERC should not mandate these minimums since to do so would require FERC to seriously interfere into almost all aspects of the traditional state role of resource procurement.

This range, however, is based on a paradigm where utilities owned their generators, controlled maintenance schedules, availability and operation. With generation ownership now scattered among a far larger number of parties (who treat each generating facility as a profit center,) maintenance schedules and practices, unit availability, cost recovery and prices are all calculated in a different way. Absent an effective market structure in the ISO (through such mechanisms as "must-offer," coordinating unit outage schedules, restricted maintenance days, and other efforts,) the appropriate reserve level might be higher, a position noted by several commentors in this rulemaking.

B. Coordination. The Power Authority agrees with commenters' concerns that coordination among parallel processes is essential. The Power Authority is participating in all of the proceedings referenced by commenters and is following the outcomes and recommendations of these proceedings. We do not agree, however that it is prudent to delay action until those proceedings are complete. Each of these proceedings is oriented to look at reserves in a particular way, and with the focus related to that entity's mission. None of these proceedings is a substitute for the statutory responsibility placed on the Power Authority. The fact that differing perspectives must be reconciled and that a balance between competing objectives must be achieved is not in question, but it also is not a valid reason to delay or postpone this proceeding. Sufficient information exists, both from historical sources and from the four or five years of operation of various markets, to make reasoned judgments and recommendations concerning the required level of reserves. In addition, recommended levels of reserves will change both over time and as the composition of resource portfolios change. Recommendations in this proceeding will of necessity be adjusted as further developments occur.

Because of the lead-time needed for new capacity additions (including demand response programs) it is clear that the development of an appropriate portfolio of short, medium and long term instruments, created from reserves of many types, is the best strategy to get needed reserves and associated reliability at the most reasonable cost. Since this planning and procurement must start now, this is all the more reason to provide the unique perspective of the Power Authority as additional input into these processes.

C. Assignment of Responsibilities. The Power Authority endorses the concept set out by many commentors that all responsibilities must be clearly and unambiguously assigned. The Power Authority does not have the mandate to assign responsibilities, but endorses the following concepts with respect to the provision of adequate reserves:

1) The Load Serving Entities (LSEs) are responsible for procuring resources needed to meet their loads and reserves as authorized by their regulator. The Power Authority recommends that the appropriate regulator take note of the recommendations of this proceeding to assist in setting the targets for individual utilities. The Power Authority also supports the idea that in a capacity adequacy framework in a hybrid competitive market, LSEs must report to the ISO on the

status of their procurement in a timely manner so that the ISO can perform its functions efficiently.

2) Regulators, such as the CPUC, govern the specifics of procurement plans for their utilities. Many factors go into the decisions of the appropriate level of procurement authorized for a particular utility. The targets set in this proceeding are not binding on regulators, but serve as a useful starting point from which to understand differences based on resource mix, historic performance, contract terms and conditions, risk tolerance, etc. In its comments, PG&E noted several questions most appropriately addressed in the confines of a utility specific proceeding governing investment decisions.

3) The CAISO operates the grid and must comply with applicable reliability criteria. In this regard, it is clear that the ISO must have the information and tools needed to perform its obligation. This includes information about capacity that is expected to serve load and keep the lights on. The ISO must know which units are committed to serve load and where, from both suppliers and consumers, at least a day ahead of the operating day, in order to perform its required reliability responsibilities.

4) Suppliers must perform in accordance with their contracts and in addition must have a reporting obligation to the ISO on the same schedule as the LSEs. One proposal endorsed by the Power Authority contains a reporting requirement for suppliers to disclose to the ISO the disposition of all their existing capacity i.e., how much is sold, how much is available, etc. at any given time. The Power Authority strongly endorses such a concept, since it would give a tool to better

estimate the actual availability of uncommitted resources. This is particularly important during peak times when the system is stressed.

D. **Investment Incentives.** Several commentors expressed concern over the effects of Power Authority investment on private investment decisions. The Power Authority is very clear that its mission is to supplement and not supplant private investment. Private investment is preferred, and the Power Authority will act in its role to assure sufficient supply when it is evident that private investors are unable or unwilling to perform this function. Current financial conditions make it difficult for many private investors to carry out plans previously announced, and there may be a role for the Power Authority in completion of essential facilities. The Power Authority may act as owner, broker or partner in assuring sufficient capacity. This action may encompass traditional resources, renewables resources or load-based resources.

E. **Demand Participation.** Using customer demand as a reserve product is not a new idea. Emergency programs for demand reserves and some limited applications of interruptible load as economically dispatched reserves have been used for a number of years. Such applications are consistent with existing reliability criteria and can be economical for both the customer and the utility. However, the changes in the electricity landscape suggest that demand may now need to play a much more active role in the new marketplace.

There are two broad categories of efforts to control demand in the energy market. The first broad category consists of numerous efficiency programs that slow growth in either peak load or total energy consumption. Efficiency standards for buildings or appliances, building retrofits, new constructions materials and methods, efficient lighting and numerous other approaches are very effective for this type of effort. The cumulative effect of these programs in California is significant and well documented by the CEC. The effects of these programs are reflected in lower peak load projections and lower overall energy consumption projections. In developing reserve requirements for future years, regulators and LSEs should factor into their calculations the effect of these energy efficiency programs. However, while these programs reduce peak load and energy use over time, they cannot be used to provide short-term operating reserve requirements.

The second broad category of demand programs seeks to reduce energy usage specifically during periods of peak demand.. This second category can be further bifurcated into two groups. First, there are customers who may reduce consumption based on the retail price of power. This may be done with time of use pricing, although this is a blunt instrument and does not reflect the real volatility of electricity prices on peak days. Some form of real-time or near real-time communication of wholesale market-based price information is a more sophisticated example of this type of program. Savings to participating customers come in the form of voluntary load reductions and the associated savings from avoided costs for the electricity not consumed. Such programs are the subject of the PUC proceeding (R02-06-001,) upcoming general rate cases, and other proceedings. The Power Authority expects that useful products will develop from that effort. As such programs mature sufficiently to develop a predictable effect of price, there is increased opportunity to firmly quantify the contribution of such programs to reserves. In the interim, resource planners may need to use probabilistic assessments to determine the effect of these programs in reducing peak demand.

The second part of this category of demand programs is essentially a dispatchable product, where a group of customers agrees to be available for curtailment for an incentive or performance payment of some type. This may be a capacity payment, an energy payment or a mix. The savings to the participating consumer comes as they calculate the incentive payment against the lost production or revenue associated with the interruption. As technology becomes more effective and universal, it will be increasingly possible to have targeted load reductions that do not affect the economics of a business, but are only an inconvenience. This offers a potentially significant new source for capacity reserves.

Both types of programs exist today and are likely to expand in the near future. Some economists have observed that peak demand participation of between 3 and 5% could be sufficient to mitigate many significant price spikes. Other studies have indicated that demand participation or price elasticity in the range of 5-10% of peak load would be sufficient to mitigate all or nearly all price spikes and attempted exercises of market power. One utility in Florida provides 70% of the needed reserves from demand programs. While this number is extraordinarily high, it is illustrative of what is possible.

Considerable concern has been expressed by some commentors that the targets for demand response may be unreasonable high. The Power Authority believes that these goals are realistic and achievable. For example, Edison currently has almost 1000 MW of Demand Response used currently for emergency purposes. This program could be modified to quickly provide over 25% of Edison's Reserves (or approximately 5% of its Dependable Capacity). As there is currently about 1800-2200 MWs of combined Demand Reserves of some type in the state, and a statewide goal of 25% reserves would require 2000-2500 MW of Demand Reserves, it would not be difficult for state's utilities and regulatory bodies to commit to a phased approach in which the 25% of Reserves goal (5% of Dependable Capacity) would be met by summer 2004 and the 50% of Reserves goal (10% of Dependable Capacity) by summer 2007. The Power Authority has already received over 500 MW of bona fide interest from end users for its Demand Reserves Partnership which gives us confidence in the feasibility of these goals.

F. Reserves – What Counts, and How Much is Needed.

Reserves serve two discrete functions. First, they are needed to meet applicable reliability criteria so as to ensure the reliable operation of the system in real-time. Second, given the change in our electricity landscape, they now perform the function of assuring market stability and of reducing market volatility and the opportunity for the exercise of market power. The more robust the reserves picture, the less opportunity for the exercise of market power or manipulation of market rules. This, plus the demonstrated market dysfunction of the last two years leads to the conclusion that more reserves are needed under a market paradigm than under a cost of service paradigm. The real question is whether or not the benefits of competition outweigh the cost of additional reserves. Under regulation, the capital cost of units is rate-based, and under a market paradigm, the unit owners take their chances of recovery in the market. A cost-benefit analysis of the paradigm shift is beyond the scope of this proceeding, but the effect is clear. A market paradigm requires more reserve capability.

In the regulated paradigm, each load serving entity knew what equipment it owned and where its energy would come from. For a market paradigm to be successful, it is likewise necessary that an LSE know, either through ownership or contracts, specifically where the power that it depends on to meet its load and reserves will come from. California is clearly not an island and has depended for many years on imports of electricity to satisfy its needs. California has also historically exported electricity to the Northwest in the off-peak season. This arrangement benefited both geographic areas by allowing better utilization of resources in each area. Under a paradigm where profit maximization is the driver, such reliance carries increased risk for both reliability and cost. Imported power should only be relied on when it is tied up in contracts. California will likely continue to be dependent on imports for the foreseeable future. These imports can and should be relied upon as an appropriate element of a reserve portfolio if they are in appropriate contractual form.

In their supplemental comments, two parties question the conclusion that additional reserves are needed under a market paradigm. The Power Authority believes that up to this time, the evidence favoring the need for additional reserves is convincing. Documented withholding, exercise of market power, and rotating outages during the past two years provide stark evidence that the new paradigm brings a host of issues not envisioned under the previous scheme. Some level of additional dependable capacity, along with clear assignment of responsibilities is the best way to manage this new set of problems. The Power Authority intends to visit this reserve target recommendation each year, as it reviews its Energy Resource Investment Plan. There will be ample opportunity at that annual review to adjust targets as needed to compensate for improvements in the market structure.

There are two other key issues affecting the level of target reserve requirements. These are uncontracted capacity, or units located in California that are not contracted to serve load in California, and the definitions and calculation of reserves.

1. <u>Uncontracted Capacity.</u> In a market paradigm, there may capacity that is installed (i.e. steel in the ground), but not under contract to any particular entity. This capacity may participate in the spot market to try to capture volatile prices. However, the economics of privately owned generation is an important factor in

considering how to account for such capacity. In the past, "steel in the ground" capacity was divided by the system peak to come up with an installed reserve calculation. This assumed that all installed capacity would be available if it could run. This is no longer appropriate in the market era. Such an approach ignores the fact that the owners/operators of the steel in the ground have no obligation to be available or to produce electricity when the system has need for the facility's output. That relationship can only be established by contract. A legitimate question, then, is "how much value should be placed on resources not under contract to any particular utility but presumably available to the system and/or the market only in spot markets?"

In Florida, for example, the Public Utilities Commission does not allow utilities to count reserves from any facility unless the utilities have a contract for its output. The Florida State Commission estimated that if contracts were signed for the output of all existing merchant generation, reserve levels of the utilities would be at 43%. Even knowing this, the Florida Commission recently directed the largest state utilities, comprising approximately 85% of the load in the state, to increase reserve margins from 15% to 20% under their direct ownership or contracts. We find the concept of discounting MWs not under contract to a load serving entity to be an appropriate concept, particularly in a market structure as dysfunctional and as rife with market power as the California market has been over the last 2 years.

There is significant capacity both in California and the West that is not under contract. Some current capacity estimates in California include all of this capacity as though it were available. This overstates the available reserves, since capacity not under contract has no obligation to provide power. The current "must offer" requirement of FERC is a temporary measure that may expire soon, probably no later than September 2004, which is the proposed implementation date of the SMD. The state has taken the position that a "must-offer" provision should be a permanent feature of a market structure, but this position has not yet been ruled on by FERC. Regardless, the current "must-offer" requirement is marginally effective in California because resources not in California have no obligation to offer to California. Furthermore, in-state resources may and indeed have tied up portions of their capacity in sales to entities out of the state.

The capacity adequacy proposal developed by the state Inter-Agency Work Group, and proposed as an alternative to the ISO capacity framework is called Advisory Forward Energy Commitment (AFEC.) Under this proposal, suppliers are required, along with LSEs to make timely reports to the ISO stating the amounts of capacity that they have sold, and what they still have available. As noted above, this framework would allow the ISO to identify what capacity was sold out of state, what was contracted to LSEs and what was remaining as potentially available to the spot market. Absent such a reporting requirement, the Power Authority finds that uncontracted capacity should not be counted toward satisfying reserve margins. This is necessary because there is no assurance that such capacity will be made available to California, if it is made available at all. With such a reporting requirement, the Power Authority finds that such uncontracted capacity be counted at 50%, to reflect the uncertainty that it will be available in any particular time frame.

There have been several recent announcements by merchant generators outlining closures of several thousand megawatts of capacity in various areas of the country. Some of these closures are reportedly for economic reasons, i.e., the plants are not able to make enough money. Some are retirements because it is not economical to make needed retrofits, upgrades and improvements to keep the plants in service. Retirement of old facilities and replacement by newer more efficient and cleaner facilities is in everyone's interest. However, closure of plants must be factored into the reserve calculation for exactly the reasons outlined above. Uncontracted capacity may exit the market at any time. New additions must keep pace with these closures and retirements if markets are to remain workable and prices are to remain reasonable.

2. <u>Definitions and Calculations.</u> "Installed capacity" describes the design capability of a unit. Limitations on that capability are critical in determining what is available for reserves and how much reserves will satisfy appropriate criteria. "Dependable capacity" is the actual capacity available at any time from all available units. As described above, dependable capacity is some reduced value from nameplate capacity. Historically, the dependable capacity of the California

fleet has been no more than 95% of the installed nameplate capability. This is particularly true at peak times when system conditions are the most restrictive.

Forced outages are another element in determining reserve margins. Historically, the system has experienced between 5-10% of available capacity that is forced out of service for mechanical or other reasons. In recent years, since generation divestiture has occurred, forced outage rates have been as high as 15-20% of the nameplate capacity. During the winter of 2000-2001, outage rates were so high that FERC and others investigated the causes for potential withholding. As noted by the CPUC in its investigation of these outages, it appears that many of these outages could not be explained as a result of mechanical problems. There are many reasons that have been postulated to explain high forced outage rates. Age of facilities, how hard they have been run and market manipulation are a partial list of potential candidates. Under the provisions of the recently passed SB39X1, the CPUC and the ISO have been empowered to develop standards for plant inspections to help ensure reliable service.

In our calculations, the Power Authority is utilizing the historic outage level of between 5-10%. As it revises its reserve targets in the future, the Power Authority will review collected data to provide information to adjust the expected level of outages for the future.

Operating reserve is an amount of capacity available in real-time in less than ten minutes. It is calculated by a formula that considers the type of generation and the operating characteristics of those resources. It may be approximated by assuming that 7% of actual load must be available to the system operator in ten minutes at all times to maintain reliability and electrical balance on the system.

Additionally, regulating reserves are units that are under direct computer control by the control area operator. These reserves respond every 4 seconds to system fluctuations. Historic regulation reserves were about 1% of system load. Recent experience with market rules and incentives in California has led the ISO to procure about 2 % of total load as regulating reserves. This has been necessary to counteract the incentives that cause unit owners to fail to respond to ISO instructions or to take other action that may not be consistent with the directions of the ISO but in their own economic interest.[4]

Finally, the control area operator must account for load forecast error. Typical load forecast error is in the range of 1-2% of system load when comparing the day-ahead forecast to the actual load on a particular day. Longer-term forecasts are far less accurate, and week-ahead forecasts can be off by 5-8% or more.

G. **Variations Between Utilities.** The purpose of this proceeding as stated at the outset is to create a reserve target for use by the Power Authority for its Energy Resource

[4] Ideally, a properly designed market structure would reduce these levels back to historic levels.

Investment Plan, and to feed into other regulatory proceedings that are making decisions about reserves. The Power Authority is not attempting to create a target that will be binding for each utility in every case, but rather to create a general starting point from which deviations might be made. Procurement decisions as to the level of reserves, technology mix of supply, and duration and terms and conditions of contracts will be made by the regulating body of each utility.

There are many reasons why individual utilities may differ from the targets suggested in this rulemaking. Type of resource must be considered. Some technologies have different operating characteristics or capabilities and should be counted differently. This is recognized in setting operating reserves, where hydro facilities are weighted differently than steam facilities. Contract terms and conditions may provide a need or reason for differences from the targets suggested here. Level or risk tolerance is another reason that one utility may differ from another in level of acquired reserves. As long as any shortages or high prices are appropriately allocated, this may be acceptable. In any case, regulators in appropriate proceeding will handle these details.

The Power Authority urges the CPUC and other regulatory bodies that vet these reserve targets and their component factors to be public and explicit about the level of reserves they are requiring for their utilities. This will allow public awareness of the weighting of factors listed above and others that may be considered in making those determinations. It will also provide needed market transparency about the intentions of the regulatory direction of the state.

As a side note, In the FERC Standard Market Design Notice of Proposed Rulemaking, FERC proposes that regional bodies made up of state regulators set reserve levels for the region. Under this approach, the reserve levels are simply apportioned to each utility, based on load ratio share of peak. This may be problematic, since it will not allow local commissions and regulators to take into account the factors listed above and other factors deemed relevant by the regulating bodies.

As a final point, it is also worth noting that there is one additional critical issue that cuts across all utilities. This is the area of transmission. The ability to deliver energy and reserves to the targeted load is a critical feature that is necessary to make reserves effective. This means that a locational aspect to reserves and the transmission constraints that affect deliverability must be an integral part of any reserve calculation. When transmission constraints become binding, reserves in the wrong area will be no more effective in avoiding blackouts than no reserves at all. Consideration of transmission issues is beyond the scope of this current rulemaking. We note it, however, because it is a critical part of determining the availability of any resource that may be counted for reserves.